Supplementary Information for

Wind and solar resource droughts in California highlight the benefits of long-term storage and integration with the Western Interconnect

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This supplementary file is 26 pages and includes 12 tables and 14 figures.

1. *Model formulation*

1.1 Nomenclature

Symbol	Unit	Description
g (superscript)	-	Generation technology (wind, solar)
v (superscript)	-	Energy conversion (electrolyzer, fuel cell)
s (superscript)	-	Energy storage (PGP storage, battery storage)
from s (superscript)	-	Discharge from energy storage
to s (superscript)	-	Charge to energy storage
t (subscript)	h	Time step, starting from 1 and ending at T
c_{capital}	\$/kW for generation or conversion \$/kWh for storage	(Overnight) capital cost
c_{fixed}	\$/kW/h for generation or conversion \$/kWh/h for storage	Fixed cost
$c_{\text{fixed O\&M}}$	\$/kW/yr	Fixed operating and maintenance (O&M) cost
c_{var}	\$/kWh	Variable cost
f	-	Capacity factor (generation technology)
h	h/year	Average number of hours per year
i	-	Discount rate
n	yrs	Project life
Δt	h	Time step size, i.e., 1 hour in the model
C	kW for generation or conversion kWh for storage	Capacity
D_t	kW	Dispatch at time step t
M_t	kWh	Demand at time step t
S_t	kWh	Energy remaining in storage at time step t
γ	1/yr	Capital recovery factor
δ	1/h	Storage decay rate, or energy loss per hour expressed as fraction of energy in storage
η	-	Storage charging efficiency
τ	h	Storage charging duration

1.2 Cost calculations

Fixed cost of generation and conversion technologies (wind, solar, electrolyzer, fuel cell):

$$c_{\text{fixed}}^{g,v} = \frac{\gamma c_{\text{capital}}^{g,v} + c_{\text{fixed O\&M}}^{g,v}}{h}$$

Fixed cost of energy storage (PGP storage, battery storage):

$$c_{\text{fixed}}^{s} = \frac{\gamma c_{\text{capital}}^{s}}{h}$$

Capital recovery factor:

$$\gamma = \frac{i(1+i)^n}{(1+i)^n - 1}$$

1.3 Constraints

Capacity:

$$C^{g,v,s} \geq 0 \qquad \forall g, v, s$$

Dispatch:

$$0 \leq D_t^g \leq C^g f_t^g \qquad \forall g, t$$
$$0 \leq D_t^v \leq C^v \qquad \forall v, t$$
$$0 \leq D_t^{\text{to } s} \leq \frac{C^s}{\tau^s} \qquad \forall s, t$$
$$0 \leq D_t^{\text{from } s} \leq \frac{C^s}{\tau^s} \qquad \forall s, t$$
$$0 \leq S_t^s \leq C^s \qquad \forall s, t$$
$$0 \leq D_t^{\text{from } s} \leq S_t^s(1-\delta^s) \qquad \forall s, t$$

Storage energy balance:

$$S_1 = (1-\delta^s)S_t\Delta t + \eta^s D_T^{\text{to } s}\Delta t - D_T^{\text{from } s}\Delta t \qquad \forall s$$
$$S_{t+1} = (1-\delta^s)S_t\Delta t + \eta^s D_t^{\text{to } s}\Delta t - D_t^{\text{from } s}\Delta t \qquad \forall s, t \in 1, \ldots, (T-1)$$

System energy balance:

$$\sum\nolimits_g D_t^g \Delta t + D_t^{\text{from } s}\Delta t = M_t + D_t^{\text{to } s}\Delta t \qquad \forall g, t$$

1.4 Objective function

$$minimize(system\ cost)$$

$$system\ cost = \sum\nolimits_g c_{fixed}^g C^g + \sum\nolimits_g \left(\frac{\sum_t c_{var}^g D_t^g}{T}\right) + \sum\nolimits_v c_{fixed}^v C^v$$
$$+ \sum\nolimits_s c_{fixed}^s C^s + \frac{\sum_t c_{var}^{to\ s} D_t^s}{T} + \frac{\sum_t c_{var}^{from\ s} D_t^s}{T}$$

2. *Supplementary figures and tables*

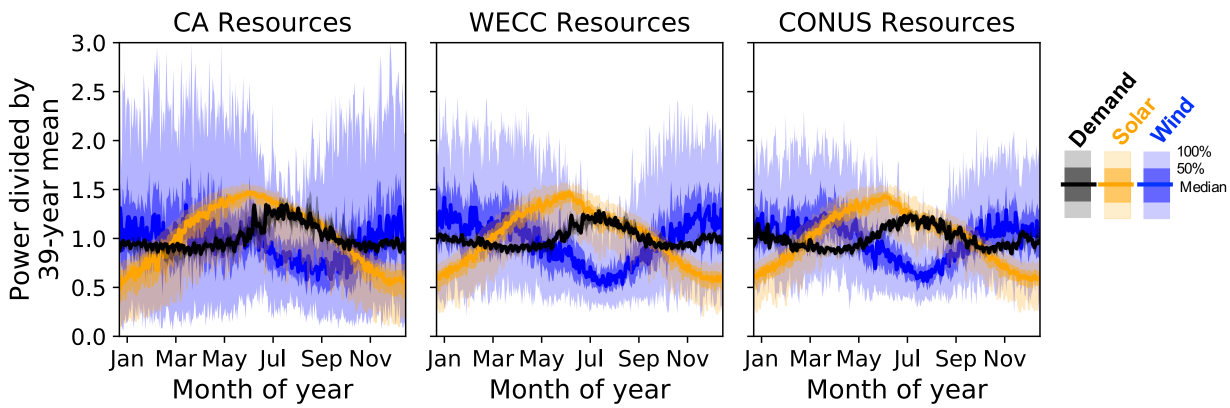

Figure S1: Temporal variability of wind (blue) and solar (yellow) resources over California, the Western Interconnect, and the contiguous U.S. during the 39-year period from 1980-2018. Seasonal variability of a single year (2018) of electricity demand (black). This figure is the same as Figure 1 with the addition of CONUS resources and demand. As in Figure 1, the dark line shows the median value and the darker and lighter shadings show the 25th to 75th and 0th to 100th percentiles of data, respectively. All data are normalized to their respective mean over the time period.

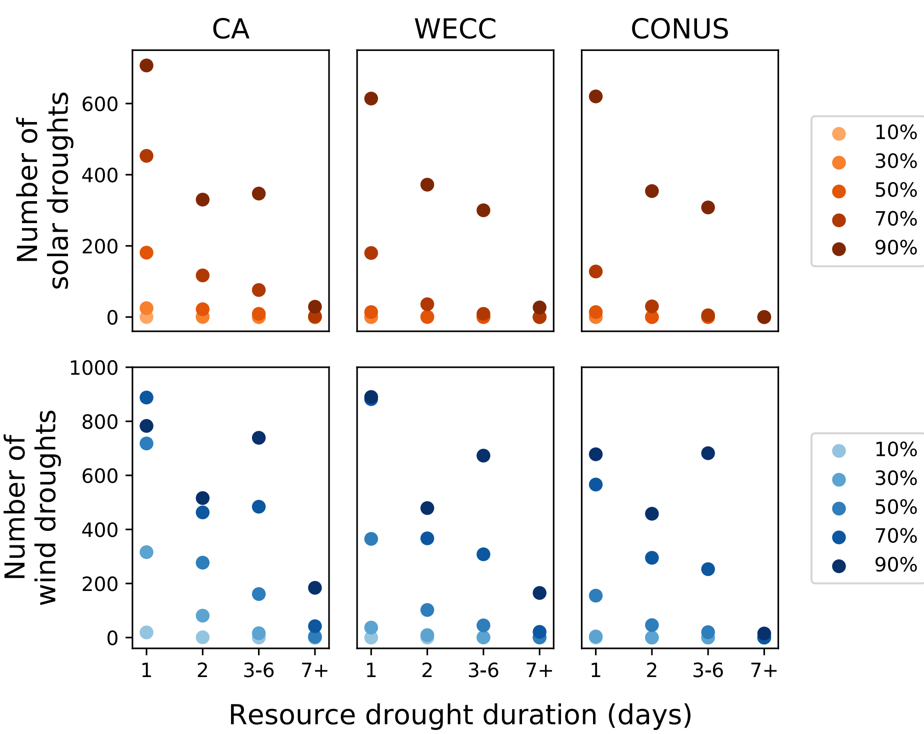

Figure S2: Resource droughts in California, the Western Interconnect, and the contiguous United States at for different threshold cutoffs. Each plot shows the number of instances where the mean daily capacity factor for solar (orange) and wind (blue) was less than the threshold percent of the mean daily capacity factor for that day of the year over the 39-year period for a duration of 1-, 2-, 3-6, or 7+ days. Resource droughts greater than 1-day in duration are not also counted toward 1-day occurrences. The threshold cutoffs are varied from 10% to 90% where darker dots indicate a higher threshold cutoff. The supporting data for this plot is in Table S1.

Wind Resource Droughts												
	1 day			2 days			3-6 days			7+ days		
	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS
10%	19	0	0	1	0	0	0	0	0	0	0	0
30%	316	37	4	81	9	0	16	1	0	0	0	0
50%	718	365	155	277	102	46	161	45	20	4	1	0
70%	888	882	566	463	367	295	484	308	253	42	21	0
90%	783	890	678	516	479	458	739	673	682	184	165	15

Solar Resource Droughts												
	1 day			2 days			3-6 days			7+ days		
	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS
10%	0	0	0	0	0	0	0	0	0	0	0	0
30%	25	0	0	1	0	0	0	0	0	0	0	0
50%	181	14	14	22	1	0	9	0	0	0	0	0
70%	453	180	128	117	36	30	76	9	5	2	0	0
90%	707	614	620	330	372	354	347	300	308	29	27	0

Table S1: Number of instances and duration of wind and solar resource droughts for California, the Western Interconnect, and the contiguous United States for different threshold cutoffs. Resource droughts are defined as days where the daily mean capacity factor is less than X% of the mean daily capacity factor for that day of the year over the 39-year period. Resource droughts greater than 1-day in duration are not also counted toward 1-day occurrences. This data is plotted in Figure S2.

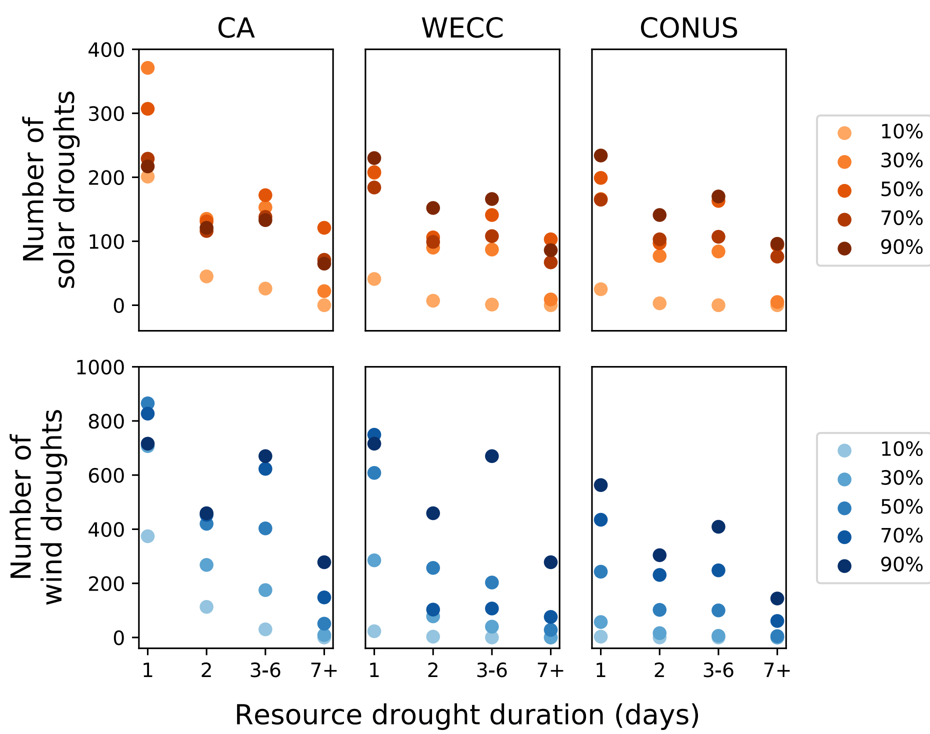

Figure S3: Resource droughts in California, the Western Interconnect, and the contiguous United States at for different capacity factor cutoffs. Each plot shows the number of instances where the mean daily capacity factor for solar (orange) and wind (blue) was less than the threshold capacity for a duration of 1-, 2-, 3-6, or 7+ days. Resource droughts greater than 1-day in duration are not also counted toward 1-day occurrences. The capacity factor cutoffs are varied from 10% to 30% where darker dots indicate a higher threshold cutoff. The supporting data for this plot is in Table S2.

Wind Resource Droughts												
	1 day			2 days			3-6 days			7+ days		
	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS
10%	374	23	3	113	3	0	30	0	0	0	0	0
15%	707	285	57	268	78	16	175	40	6	9	0	0
20%	865	608	243	420	257	102	403	203	100	51	28	5
25%	827	749	435	453	103	231	623	107	248	148	76	61
30%	716	716	563	459	459	304	670	670	409	278	278	144

Solar Resource Droughts												
	1 day			2 days			3-6 days			7+ days		
	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS	CA	WECC	CONUS
10%	201	41	25	45	7	3	26	1	0	0	0	0
15%	371	207	166	135	90	77	153	87	84	22	9	5
20%	307	208	199	131	106	97	172	141	163	121	103	94
25%	229	184	165	116	99	103	138	108	107	71	67	76
30%	217	230	234	121	152	141	133	166	170	65	86	96

Table S2: Number of instances and duration of wind and solar resource droughts for California, the Western Interconnect, and the contiguous United States for different threshold cutoffs. Resource droughts are defined as days where the daily mean capacity factor is less than X% of the mean daily capacity factor for that day of the year over the 39-year period. Resource droughts greater than 1-day in duration are not also counted toward 1-day occurrences. This data is plotted in Figure S2.

	Solar resource droughts			Wind resource droughts		
Drought duration (days)	CA	WECC	CONUS	CA	WECC	CONUS
1	181	14	14	718	365	155
2	22	1	0	277	102	46
3	7	0	0	94	33	14
4	1	0	0	44	5	4
5	0	0	0	16	5	1
6	1	0	0	7	2	1
7	0	0	0	2	1	0
8	0	0	0	1	0	0
9	0	0	0	0	0	0
10	0	0	0	1	0	0
Total drought days	256	16	14	1884	732	316

Table S3: Number of instances and duration of solar and wind resource droughts for California, WECC, and CONUS over the 39-year period from 1980-2018. Resource droughts are defined as days where the daily mean capacity factor is less than 50% of the mean daily capacity factor for that day of the year over the 39-year period. Resource droughts greater than 1-day in duration are not also counted toward 1-day occurrences.

SOLAR	1 day		2 days		3-6 days		7+ days	
Year	CA	WECC	CA	WECC	CA	WECC	CA	WECC
1980	4	2	1	0	0	0	0	0
1981	7	0	0	0	0	0	0	0
1982	12	0	3	0	0	0	0	0
1983	5	0	2	1	1	0	0	0
1984	0	1	0	0	0	0	0	0
1985	4	0	1	0	0	0	0	0
1986	5	1	0	0	0	0	0	0
1987	6	0	0	0	0	0	0	0
1988	2	1	0	0	1	0	0	0
1989	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0
1991	3	2	1	0	0	0	0	0
1992	7	1	0	0	0	0	0	0
1993	6	1	1	0	0	0	0	0
1994	4	0	0	0	0	0	0	0
1995	7	0	1	0	1	0	0	0
1996	7	0	2	0	1	0	0	0
1997	6	0	2	0	0	0	0	0
1998	8	0	1	0	0	0	0	0
1999	0	0	0	0	0	0	0	0
2000	7	0	1	0	1	0	0	0
2001	5	0	0	0	1	0	0	0
2002	1	0	0	0	0	0	0	0
2003	8	0	0	0	1	0	0	0
2004	5	0	1	0	0	0	0	0
2005	10	2	0	0	0	0	0	0
2006	6	0	1	0	0	0	0	0
2007	4	0	0	0	0	0	0	0
2008	2	0	2	0	0	0	0	0
2009	7	1	0	0	0	0	0	0
2010	3	0	0	0	2	0	0	0
2011	3	1	0	0	0	0	0	0
2012	4	0	0	0	0	0	0	0
2013	1	0	0	0	0	0	0	0
2014	5	0	0	0	0	0	0	0
2015	1	1	0	0	0	0	0	0
2016	4	0	1	0	0	0	0	0
2017	7	0	0	0	0	0	0	0
2018	5	0	1	0	0	0	0	0
median	5	0	0	0	0	0	0	0
mean	4.64	0.36	0.56	0.03	0.23	0	0	0
std	2.82	0.63	0.79	0.16	0.48	0	0	0
min	0	0	0	0	0	0	0	0
25%	3	0	0	0	0	0	0	0
50%	5	0	0	0	0	0	0	0
75%	7	1	1	0	0	0	0	0
max	12	2	3	1	2	0	0	0

Table S4: Solar drought events per year for CA and WECC. Solar droughts are defined as days where the daily mean capacity factor is less than 50% of the mean capacity factor for that day over the 39-year period from 1980-2018. This table supports Figure 2.

WIND	1 day		2 days		3-6 days		7+ days	
Year	CA	WECC	CA	WECC	CA	WECC	CA	WECC
1980	14	6	3	1	7	2	0	0
1981	17	12	5	6	3	0	0	1
1982	16	10	9	4	4	0	0	0
1983	21	10	6	5	2	2	0	0
1984	22	7	9	2	2	1	0	0
1985	22	5	4	3	3	3	1	0
1986	17	7	7	4	6	1	0	0
1987	15	14	8	4	11	3	0	0
1988	20	14	13	1	4	0	0	0
1989	16	6	3	5	4	0	0	0
1990	18	8	9	1	5	1	0	0
1991	19	9	8	0	2	1	0	0
1992	20	10	10	4	6	2	0	0
1993	16	11	10	2	3	1	0	0
1994	17	8	6	3	5	1	0	0
1995	21	14	9	3	3	2	1	0
1996	19	*6*	6	4	0	0	0	0
1997	19	16	6	3	2	1	0	0
1998	18	13	8	5	2	1	0	0
1999	22	6	6	1	3	0	0	0
2000	18	8	8	3	7	1	0	0
2001	21	11	5	4	2	3	0	0
2002	21	12	4	1	5	3	0	0
2003	18	12	5	2	7	2	0	0
2004	14	15	8	3	5	1	0	0
2005	25	9	6	8	5	2	0	0
2006	15	11	9	0	3	1	0	0
2007	15	11	13	2	4	1	0	0
2008	28	3	8	1	4	0	0	0
2009	12	6	7	3	4	0	0	0
2010	17	6	5	1	3	4	0	0
2011	19	5	6	1	3	0	0	0
2012	18	8	5	0	4	1	0	0
2013	17	8	6	2	6	0	0	0
2014	22	7	4	2	5	0	0	0
2015	21	11	7	3	8	3	1	0
2016	17	8	9	2	4	1	0	0
2017	16	7	9	2	2	0	1	0
2018	15	15	8	1	3	0	0	0
median	18	9	7	2	4	1	0	0
mean	18.41	9.36	7.10	2.62	4.13	1.15	0.10	0.03
std	3.20	3.25	2.36	1.76	2.07	1.11	0.31	0.16
min	12	3	3	0	0	0	0	0
25%	16	7	5.5	1	3	0	0	0
50%	18	9	7	2	4	1	0	0
75%	21	11.5	9	4	5	2	0	0
max	28	16	13	8	11	4	1	1

Table S5: Wind drought events per year for CA and WECC. Wind droughts are defined as days where the daily mean capacity factor is less than 50% of the mean capacity factor for that day over the 39-year period from 1980-2018. This table supports Figure 2.

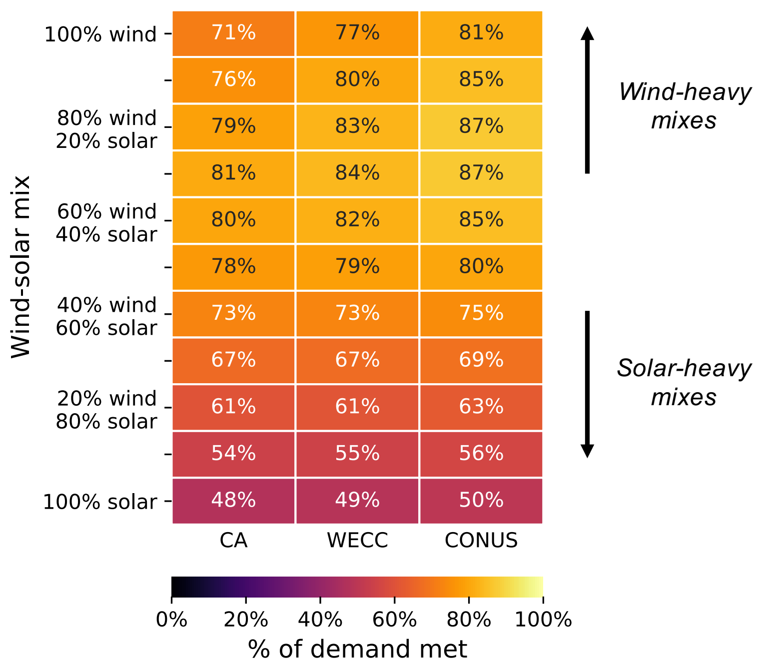

Figure S4: Percent demand met over the 39-year period from 1980-2018 for wind and solar based electricity systems. Each plot shows the potential of renewable resources to meet electricity demand for California (left column), the Western Interconnect (middle column), and the contiguous United States (right column). Each row corresponds to a different wind/solar generation mix. Marked percentages refer to the reliability (% of demand met) over the entire 39-year period for each region and mix.

Demand region	Generation region	Technology mix	Wind 1	Wind 2	Solar 1	Solar 2	PGP	Battery	Total system cost
CA	CA	wind 1, solar 1, battery	0.06	-	0.07	-	-	0.06	0.18
CA	WECC	wind 1, wind 2, solar 1, solar 2, battery	0.04	0.06	0.02	0.04	-	0.02	0.17
WECC	WECC	wind 1, solar 1, battery	0.07	-	0.05	-	-	0.03	0.16
CA	CA	wind 1, solar 1, battery, PGP	0.04	-	0.04	-	0.04	0.02	0.15
CA	WECC	wind 1, wind 2, solar 1, solar 2, battery, PGP	0.01	0.04	0.03	0.00	0.04	0.01	0.13
WECC	WECC	wind 1, solar 1, battery, PGP	0.05	0.00	0.03	-	0.04	0.01	0.13

Table S6: System cost contributions for technology mixes and geographical regions. This data table supports Figure 4. Rounded values in each technology column represent the cost contribution in $/kWh for that technology to the total system cost. Costs for PGP include both power-related and energy-related costs. Exact values, not the rounded values shown here, were used for secondary calculations. When included, wind 2 and solar 2 refer to the wind and solar resources from the rest of WECC (not including CA).

Demand region	Generation region	Technology mix	PGP input power capacity, electrolyzers (1 kW = mean demand)	PGP energy capacity (hours of mean demand)	PGP output power capacity, fuel cells (1 kW = mean demand)	Duration (hours)
CA	CA	wind 1, solar 1, battery, PGP	0.32	388.61	0.48	812.16
CA	WECC	wind 1, solar 1, wind 2, solar 2, battery, PGP	0.27	495.04	0.61	806.74
WECC	WECC	wind 1, solar 1, battery, PGP	0.26	423.73	0.51	832.41

Table S7: PGP energy and power capacities for technology mixes and geographical regions. Rounded values for the PGP input power capacity (electrolyzers), PGP energy capacity, and PGP ouput power capacity (fuel cells) are given for each geographical scenario. The values are in terms of mean demand from the specified demand region. This data table supports Figure 4.

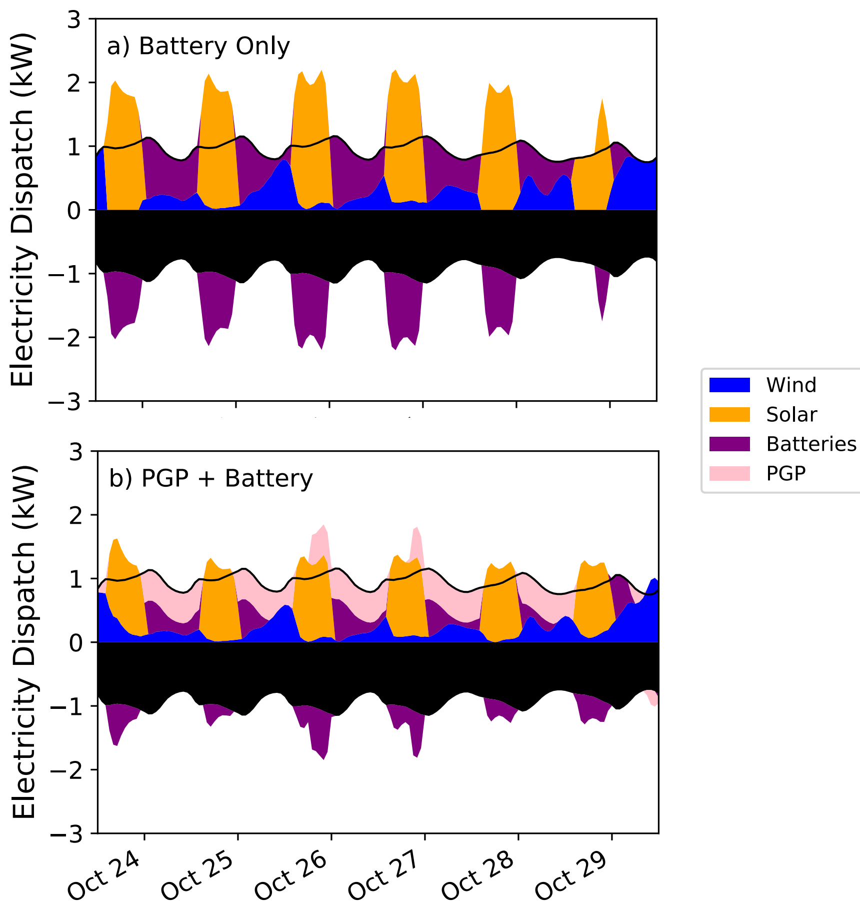

Figure S5: Electricity dispatch during a 5 day wind drought for the CA_g-CA_d case. Electricity sources (positive values) and sinks (negative values) to the grid are balanced for each hour during the optimization period (2018). Plots show the 5-day averaged results over a wind drought lasting from October 24 to October 29 for a system with battery storage only (a) and for a system with both PGP and battery storage (b). Generation sources (wind and solar) and dispatch from storage are balanced by end-use demand and charging of storage for each hour.

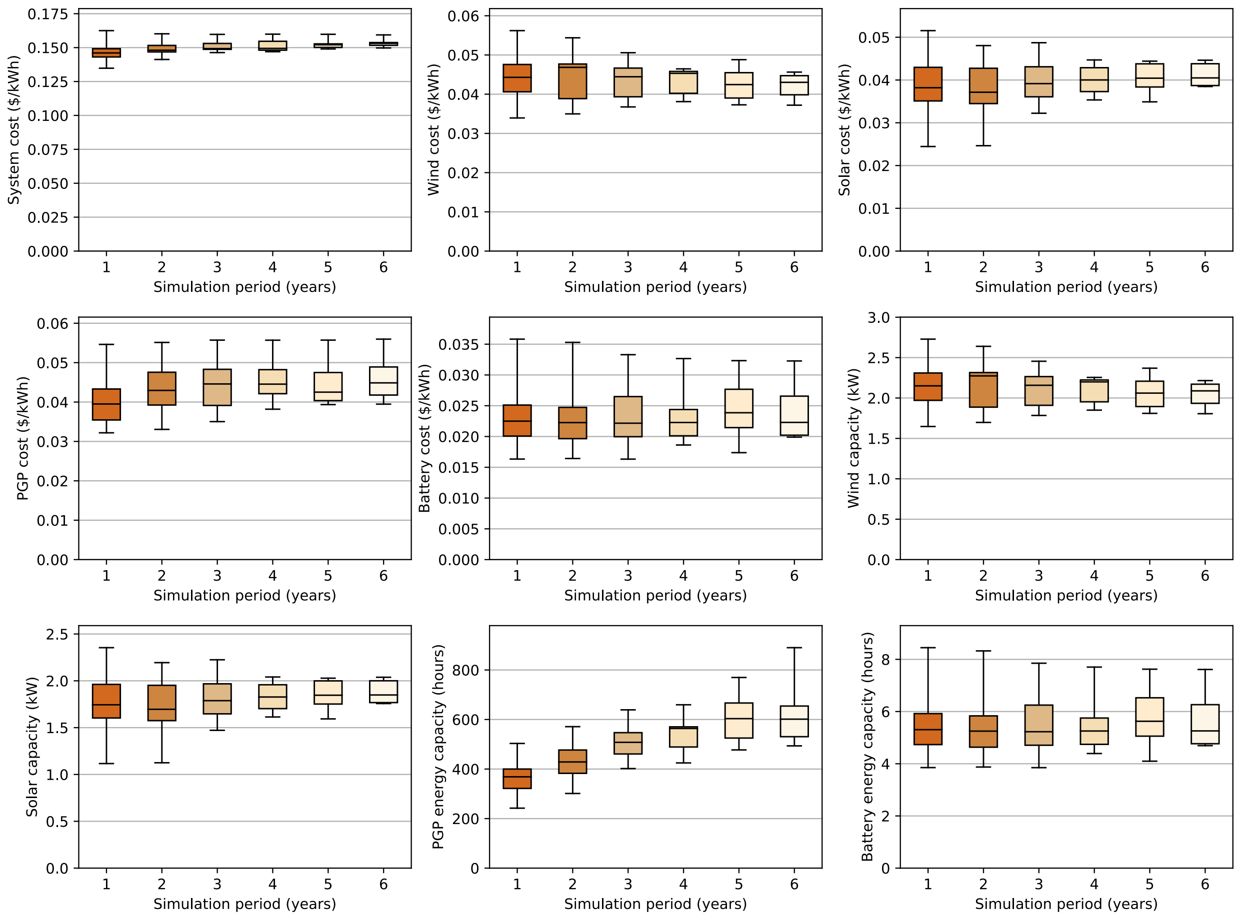

Figure S6: Distribution of results for the CA_g-CA_d scenario for various simulation lengths. Box and whisker plots show the distribution of system costs as well as the installed capacities and cost contributions for all storage and generation technologies over various simulation lengths (1- to 6-year lengths). Whiskers represent the minimum and maximum of each dataset. Power capacities are normalized such that 1 kW is mean CA demand and energy capacity is presented in hours of mean CA demand. Supporting data for this plot is in Table S8 and Table S9.

Simulation length (across 39 years, 1980-2018)	Data type	Wind power capacity (1 kW = mean CA demand)	Solar power capacity (1 kW = mean CA demand)	PGP energy capacity (hours of mean CA demand)	Battery energy capacity (hours of mean CA demand)
1-yr periods (start years: 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018)	Max	2.73	2.35	503.36	8.45
	Q3	2.31	1.96	400.01	5.92
	Median	2.15	1.74	368.65	5.31
	Q1	1.97	1.60	321.78	4.73
	Min	1.65	1.12	242.12	3.85
	spread	66.0 %	111.0 %	108.0 %	119.0 %
2-yr periods (start years: 1980, 1982, 1984, 1986, 1988, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, 2010, 2012, 2014, 2016, 2018)	Max	2.64	2.19	571.12	8.32
	Q3	2.32	1.95	476.88	5.83
	Median	2.27	1.70	428.65	5.25
	Q1	1.89	1.58	382.78	4.63
	Min	1.70	1.13	301.37	3.87
	spread	55.0 %	95.0 %	90.0 %	115.0 %
3-yr periods (start years: 1980, 1983, 1986, 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016)	Max	2.46	2.23	639.021	7.85
	Q3	2.27	1.97	546.93	6.25
	Median	2.16	1.79	507.85	5.23
	Q1	1.91	1.65	460.83	4.71
	Min	1.78	1.47	401.91	3.85
	spread	38.0 %	51.0 %	59.0 %	104.0 %
4-yr periods (start years: 1980, 1984, 1988, 1992, 1996, 2000, 2004, 2008, 2012, 2016)	Max	2.26	2.04	659.51	7.70
	Q3	2.22	1.96	570.40	5.75
	Median	2.2	1.83	563.81	5.25
	Q1	1.95	1.70	489.02	4.74
	Min	1.85	1.61	424.72	4.39
	spread	22.0 %	26.0 %	55.0 %	75.0 %
5-yr periods (start years: 1980, 1985, 1990, 1995, 2000, 2005, 2010, 2015)	Max	2.37	2.03	769.66	7.62
	Q3	2.21	2.00	666.67	6.53
	Median	2.06	1.85	603.53	5.63
	Q1	1.89	1.75	525.14	5.06
	Min	1.81	1.59	477.21	4.10
	spread	31.0 %	27.0 %	61.0 %	86.0 %
6-yr periods (start years: 1980, 1986, 1992, 1998, 2004, 2010, 2016)	Max	2.22	2.04	890.03	7.61
	Q3	2.17	2.0	654.41	6.26
	Median	2.09	1.85	601.41	5.26
	Q1	1.93	1.77	530.66	4.77
	Min	1.81	1.76	493.56	4.69
	spread	23.0 %	16.0 %	80.0 %	62.0 %

Table S8: Distribution of capacities for various simulation lengths for the CA_g CA_d scenario. This table supports Figure S5. Spread is defined as the relative difference between the max and the min: (max-min)/min x 100.

Simulation length (across 39 years, 1980-2018)	Data type	Total system cost ($/kWh)	Wind cost ($/kWh)	Solar cost ($/kWh)	PGP cost ($/kWh)	Battery cost ($/kWh)
1-yr periods (start years: 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018)	Max Q3 Median Q1 Min spread	0.163 0.149 0.146 0.143 0.135 21.0 %	0.056 0.048 0.044 0.041 0.034 66.0 %	0.052 0.043 0.038 0.035 0.024 111.0 %	0.055 0.043 0.04 0.035 0.032 70.0 %	0.036 0.025 0.022 0.02 0.016 119.0 %
2-yr periods (start years: 1980, 1982, 1984, 1986, 1988, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, 2010, 2012, 2014, 2016, 2018)	Max Q3 Median Q1 Min spread	0.16 0.152 0.148 0.147 0.141 13.0 %	0.054 0.048 0.047 0.039 0.035 55.0 %	0.048 0.043 0.037 0.034 0.025 95.0 %	0.055 0.048 0.043 0.039 0.033 67.0 %	0.035 0.025 0.022 0.02 0.016 115.0 %
3-yr periods (start years: 1980, 1983, 1986, 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016)	Max Q3 Median Q1 Min spread	0.16 0.153 0.149 0.149 0.146 9.0 %	0.051 0.047 0.044 0.039 0.037 38.0 %	0.049 0.043 0.039 0.036 0.032 51.0 %	0.056 0.048 0.045 0.039 0.035 59.0 %	0.033 0.026 0.022 0.02 0.016 104.0 %
4-yr periods (start years: 1980, 1984, 1988, 1992, 1996, 2000, 2004, 2008, 2012, 2016)	Max Q3 Median Q1 Min spread	0.16 0.155 0.149 0.148 0.147 9.0 %	0.046 0.046 0.045 0.04 0.038 22.0 %	0.045 0.043 0.04 0.037 0.035 26.0 %	0.056 0.048 0.045 0.042 0.038 46.0 %	0.033 0.024 0.022 0.02 0.019 75.0 %
5-yr periods (start years: 1980, 1985, 1990, 1995, 2000, 2005, 2010, 2015)	Max Q3 Median Q1 Min spread	0.16 0.153 0.152 0.15 0.149 7.0 %	0.049 0.045 0.042 0.039 0.037 31.0 %	0.044 0.044 0.04 0.038 0.035 27.0 %	0.056 0.047 0.043 0.04 0.039 42.0 %	0.032 0.028 0.024 0.021 0.017 86.0 %
6-yr periods (start years: 1980, 1986, 1992, 1998, 2004, 2010, 2016)	Max Q3 Median Q1 Min spread	0.159 0.154 0.153 0.152 0.15 6.0 %	0.046 0.045 0.043 0.04 0.037 23.0 %	0.045 0.044 0.04 0.039 0.038 16.0 %	0.056 0.049 0.045 0.042 0.039 42.0 %	0.032 0.027 0.022 0.02 0.02 62.0 %

Table S9: Distribution of cost contributions for various simulation lengths for the CA_g CA_d scenario. This table supports Figure S5. Spread is defined as the relative difference between the max and the min: (max-min)/min x 100.

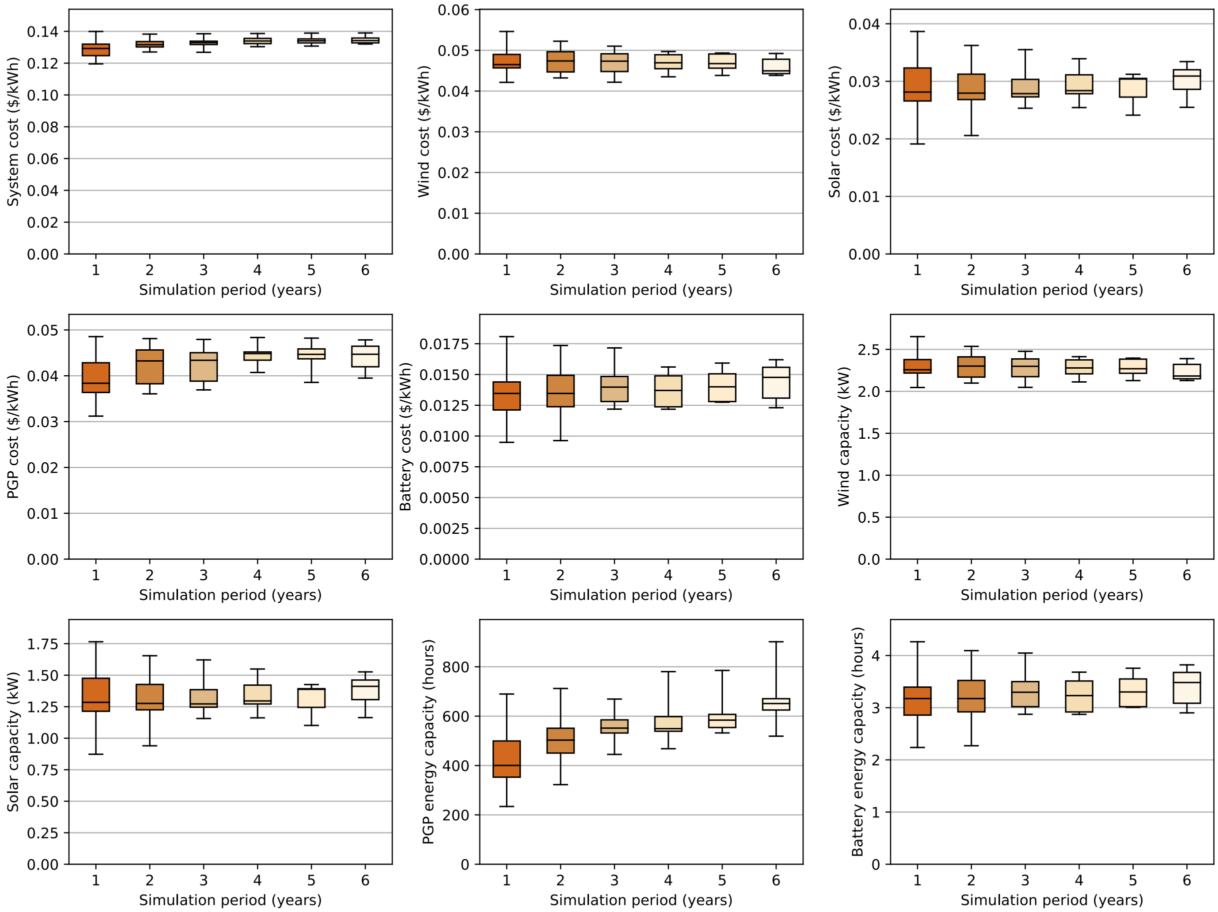

Figure S7: Distribution of results for the WECC_g WECC_d scenario for various simulation lengths. Box and whisker plots show the distribution of system costs as well as the installed capacities and cost contributions for all storage and generation technologies over various simulation lengths (1- to 6-year lengths). Whiskers represent the minimum and maximum of each dataset. Power capacities are normalized such that 1 kW is mean WECC demand and energy capacity is presented in hours of mean WECC demand. Supporting data for this plot is in Table S10 and Table S11.

Simulation length (across 39 years, 1980-2018)	Data type	Wind power capacity (1 kW = mean WECC demand)	Solar power capacity (1 kW = mean WECC demand)	PGP energy capacity (hours of mean WECC demand)	Battery energy capacity (hours of mean WECC demand)
1-yr periods (start years: 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018)	Max Q3 Median Q1 Min spread	2.65 2.38 2.26 2.22 2.05 30.0 %	1.77 1.48 1.29 1.21 0.87 102.0 %	689.59 499.43 400.34 352.82 234.09 195.0 %	4.26 3.39 3.18 2.86 2.24 90.0 %
2-yr periods (start years: 1980, 1982, 1984, 1986, 1988, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, 2010, 2012, 2014, 2016, 2018)	Max Q3 Median Q1 Min spread	2.54 2.41 2.3 2.17 2.10 21.0 %	1.65 1.43 1.28 1.23 0.94 76.0 %	712.11 551.08 502.92 450.47 322.58 121.0 %	4.09 3.52 3.18 2.92 2.27 80.0 %
3-yr periods (start years: 1980, 1983, 1986, 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016)	Max Q3 Median Q1 Min spread	2.48 2.39 2.30 2.18 2.05 21.0 %	1.62 1.39 1.27 1.25 1.16 40.0 %	669.27 585.00 551.63 531.78 445.09 50.0 %	4.05 3.5 3.30 3.02 2.87 41.0 %
4-yr periods (start years: 1980, 1984, 1988, 1992, 1996, 2000, 2004, 2008, 2012, 2016)	Max Q3 Median Q1 Min spread	2.41 2.38 2.28 2.21 2.11 14.0 %	1.55 1.42 1.30 1.27 1.16 33.0 %	780.34 598.08 549.41 538.84 468.04 67.0 %	3.68 3.51 3.23 2.92 2.87 28.0 %
5-yr periods (start years: 1980, 1985, 1990, 1995, 2000, 2005, 2010, 2015)	Max Q3 Median Q1 Min spread	2.40 2.38 2.27 2.22 2.13 13.0 %	1.43 1.39 1.39 1.25 1.10 29.0 %	785.22 607.16 583.90 554.01 532.12 48.0 %	3.76 3.55 3.30 3.02 3.01 25.0 %
6-yr periods (start years: 1980, 1986, 1992, 1998, 2004, 2010, 2016)	Max Q3 Median Q1 Min spread	2.39 2.32 2.18 2.15 2.13 12.0 %	1.53 1.46 1.41 1.31 1.16 31.0 %	901.35 670.65 651.14 624.83 518.94 74.0 %	3.82 3.68 3.48 3.09 2.90 32.0 %

Table S10: Distribution of capacities for various simulation lengths for the $WECC_g$ $WECC_d$ scenario. This table supports Figure S6. Spread is defined as the relative difference between the max and the min: (max-min)/min x 100.

Simulation length (across 39 years, 1980-2018)	Data type	Total system cost ($/kWh)	Wind cost ($/kWh)	Solar cost ($/kWh)	PGP cost ($/kWh)	Battery cost ($/kWh)
1-yr periods (start years: 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018)	Max Q3 Median Q1 Min spread	0.14 0.132 0.129 0.125 0.12 17.0 %	0.055 0.049 0.046 0.046 0.042 30.0 %	0.039 0.032 0.028 0.027 0.019 102.0 %	0.049 0.043 0.038 0.036 0.031 56.0 %	0.018 0.014 0.013 0.012 0.009 90.0 %
2-yr periods (start years: 1980, 1982, 1984, 1986, 1988, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, 2010, 2012, 2014, 2016, 2018)	Max Q3 Median Q1 Min spread	0.138 0.134 0.132 0.13 0.127 9.0 %	0.052 0.05 0.047 0.045 0.043 21.0 %	0.036 0.031 0.028 0.027 0.021 76.0 %	0.048 0.046 0.043 0.038 0.036	0.017 0.015 0.013 0.012 0.01 80.0 %
3-yr periods (start years: 1980, 1983, 1986, 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016)	Max Q3 Median Q1 Min spread	0.138 0.134 0.133 0.132 0.127 9.0 %	0.051 0.049 0.047 0.045 0.042 21.0 %	0.036 0.03 0.028 0.027 0.025 40.0 %	0.048 0.045 0.043 0.039 0.037 30.0 %	0.017 0.015 0.014 0.013 0.012 41.0 %
4-yr periods (start years: 1980, 1984, 1988, 1992, 1996, 2000, 2004, 2008, 2012, 2016)	Max Q3 Median Q1 Min spread	0.139 0.136 0.134 0.132 0.13 6.0 %	0.05 0.049 0.047 0.045 0.044 14.0 %	0.034 0.031 0.028 0.028 0.025 33.0 %	0.048 0.045 0.045 0.043 0.041 19.0 %	0.016 0.015 0.014 0.012 0.012 28.0 %
5-yr periods (start years: 1980, 1985, 1990, 1995, 2000, 2005, 2010, 2015)	Max Q3 Median Q1 Min spread	0.139 0.135 0.134 0.133 0.131 6.0 %	0.049 0.049 0.047 0.046 0.044 13.0 %	0.031 0.031 0.03 0.027 0.024 29.0 %	0.048 0.046 0.045 0.044 0.039 25.0 %	0.016 0.015 0.014 0.013 0.013 25.0 %
6-yr periods (start years: 1980, 1986, 1992, 1998, 2004, 2010, 2016)	Max Q3 Median Q1 Min spread	0.139 0.136 0.134 0.133 0.132 5.0 %	0.049 0.048 0.045 0.044 0.044 12.0 %	0.033 0.032 0.031 0.029 0.025 31.0 %	0.048 0.046 0.045 0.042 0.039 21.0 %	0.016 0.016 0.015 0.013 0.012 32.0 %

Table S11: Distribution of cost contributions for various simulation lengths for the $WECC_g$ $WECC_d$ scenario. This table supports Figure S5. Spread is defined as the relative difference between the max and the min: (max-min)/min x 100.

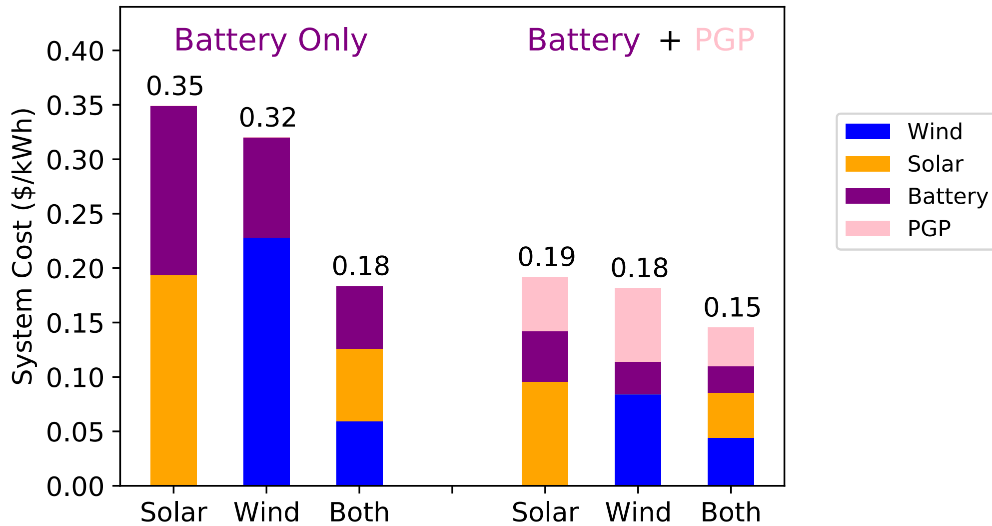

Figure S8: System costs for scenarios meeting California electricity demand with California resources using various generation and storage technologies. The leftmost three bars represent systems with battery storage only and the rightmost three bars represent systems with both battery and PGP storage. Within these groupings, the leftmost bar includes only solar generation, the middle bar includes only wind generation, and the right bar includes both wind and solar generation. Stacked areas in each bar correspond to the total system cost contribution from each technology over the optimization period.

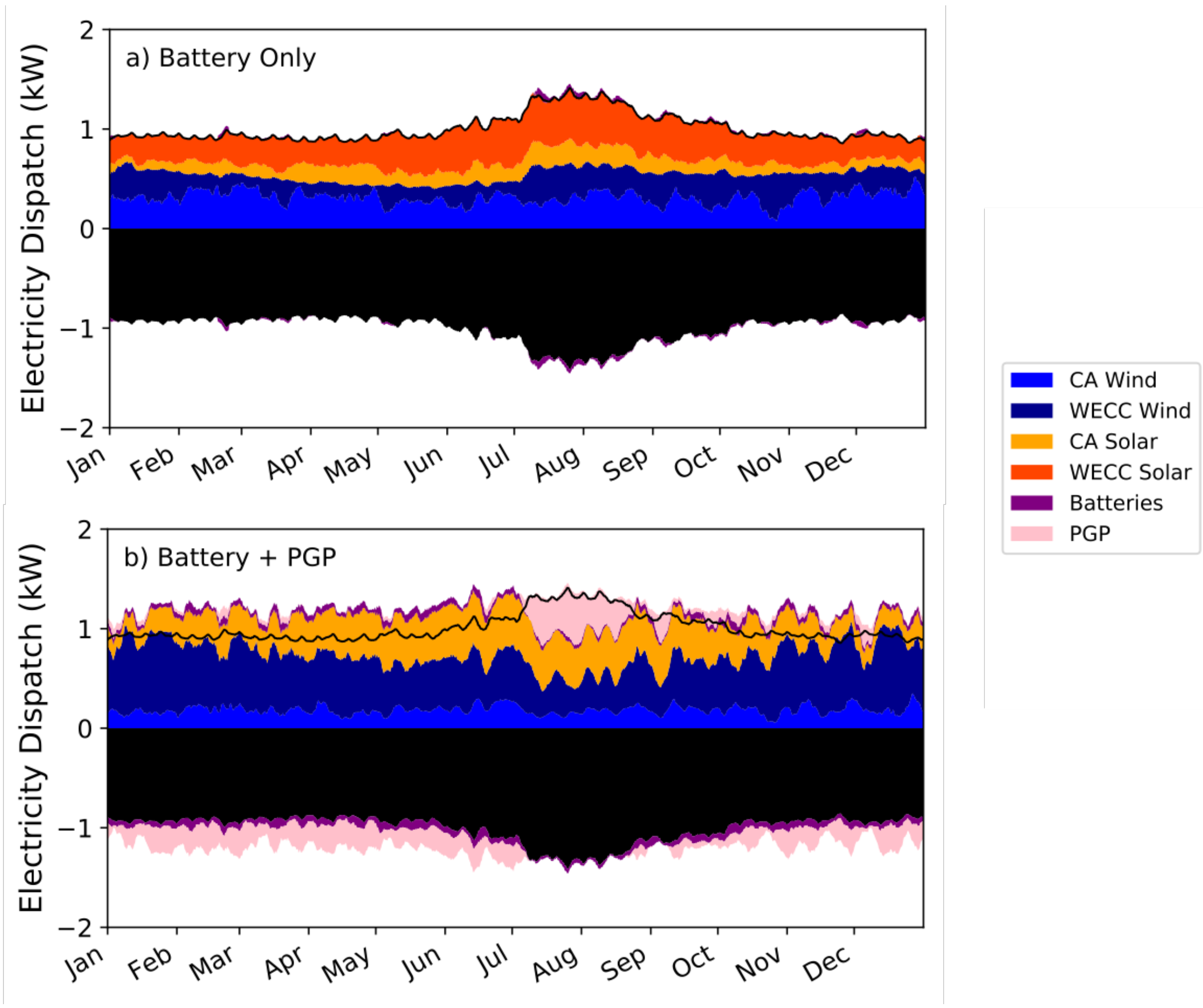

Figure S9: Dispatch schedule for the WECC$_g$-CA$_d$ cases. Electricity sources (positive values) and sinks (negative values) to the grid are balanced for each hour during the optimization period (2018). (a) 5-day averaged annual results for a system with battery storage only (b) 5- day averaged annual results for a system with both PGP and battery storage. Generation sources (wind and solar) from both CA and the Western Interconnect and dispatch from storage are balanced by end-use demand and charging of storage for each hour.

Wind Capacity (MW)	Batt only		PGP + Batt	
	Solar Capacity (MW)	% Wind of Total Generation Capacity	Solar Capacity (MW)	% Wind of Total Generation Capacity
5000	266187	1.84	130987	3.68
10000	254039	3.79	124397	7.44
15000	241891	5.84	117931	11.28
20000	229744	8.01	111640	15.19
25000	218473	10.27	105582	19.15
30000	211568	12.42	98489	23.35
35000	204663	14.60	91800	27.60
40000	197757	16.82	87102	31.47
45000	190852	19.08	81397	35.60
50000	183946	21.37	76048	39.67
55000	177041	23.70	70693	43.76
60000	170136	26.07	66461	47.45
65000	163230	28.48	61031	51.57
70000	155571	31.03	57079	55.08
75000	143690	34.30	-	-
80000	132005	37.73	-	-
85000	120320	41.40	-	-
90000	99268	47.55	-	-

Table S12: Installed solar capacity and % wind of total generation capacity for specified wind capacity optimizations. Results for optimizations where the capacity of installed wind is specified but all other technologies optimize freely. This table supports Figure 5.

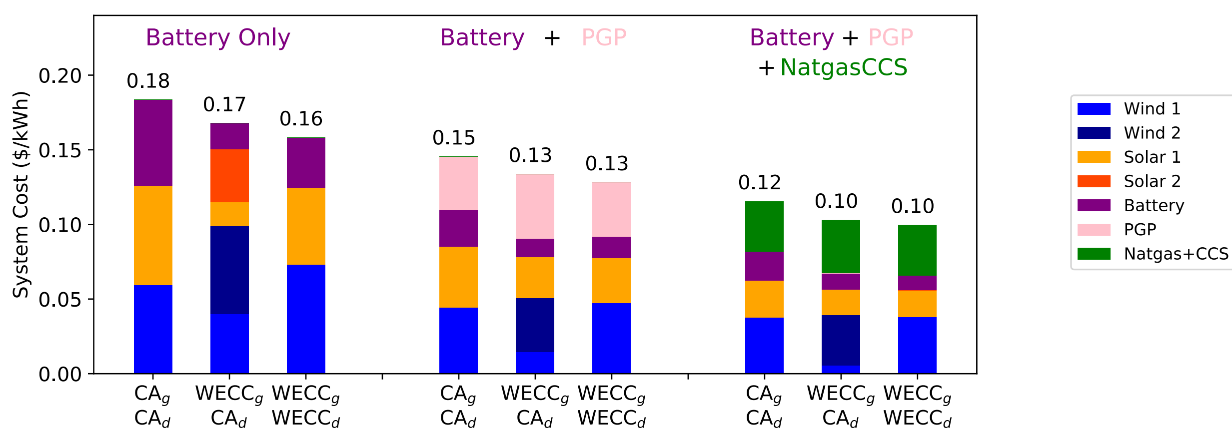

Figure S10: System costs for different resource regions, demand regions, and technology combinations including natural gas with CCS. For bars labeled CA_g CA_d, CA electricity demand is met with CA wind/solar generation. For bars labeled $WECC_g$ CA_d, CA electricity demand is met with wind/solar generation from both CA and the rest of WECC. For bars labeled $WECC_g$ $WECC_d$, WECC electricity demand is met with WECC wind/solar generation. The leftmost three bars represent systems with battery storage only, the middle three bars represent systems with both battery and PGP storage, and the rightmost three bars represent systems with battery storage, PGP storage, and generation from natural gas with CCS. When included, the annual dispatch of natural gas with CCS was limited to 20% of total demand. Stacked areas in each bar correspond to the total system cost contribution from each technology over the optimization period (2018).

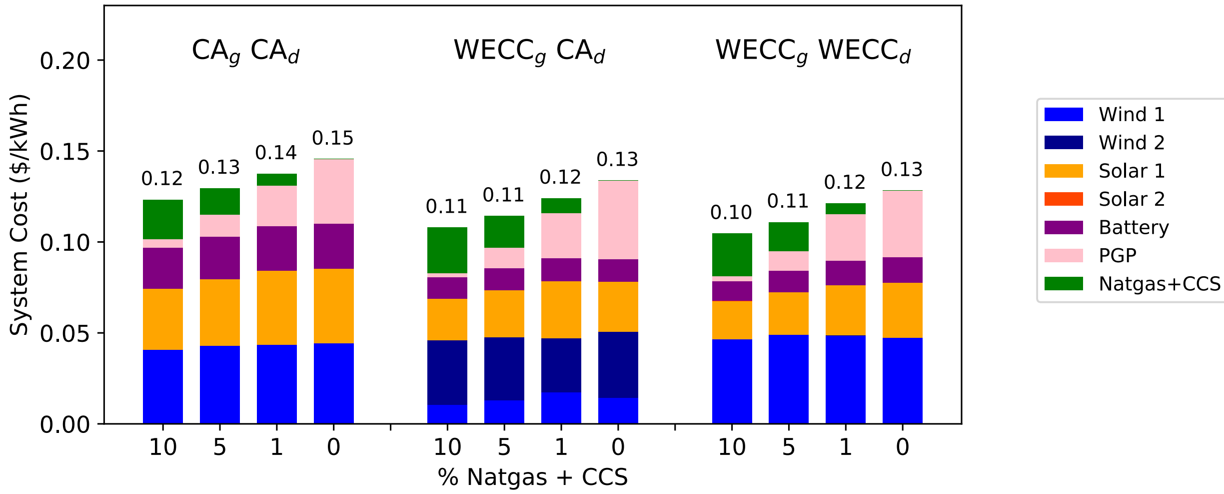

Figure S11: System costs for least cost systems where natural gas + CCS meets 10, 5, 1, and 0% of demand. For bars labeled CA_g CA_d, CA electricity demand is met with CA wind/solar generation. For bars labeled $WECC_g$ CA_d, CA electricity demand is met with wind/solar generation from both CA and the rest of WECC. For bars labeled $WECC_g$ $WECC_d$, WECC electricity demand is met with WECC wind/solar generation. Stacked areas in each bar correspond to the total system cost contribution from each technology over the optimization period (2018). As more natural gas with CCS is allowed in the system, PGP. When annual dispatch of natural gas with CCS is limited to 20% of total demand, PGP is entirely eliminated from the system (Figure S5).

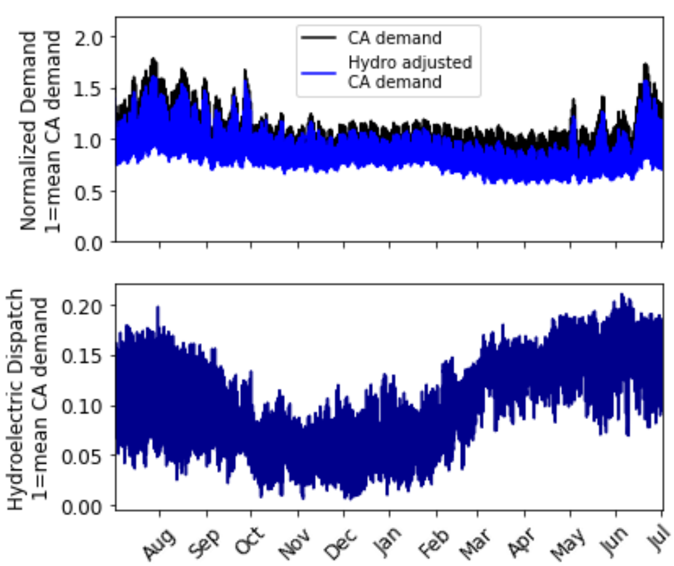

Figure S12: California demand adjusted for hydroelectric dispatch. The top panel shows normalized California demand from July 2016 to July 2017 before (black) and after (blue) subtracting hydroelectric dispatch. The bottom panel shows hourly, historic hydroelectric dispatch from July 2018 to 2019.[1]

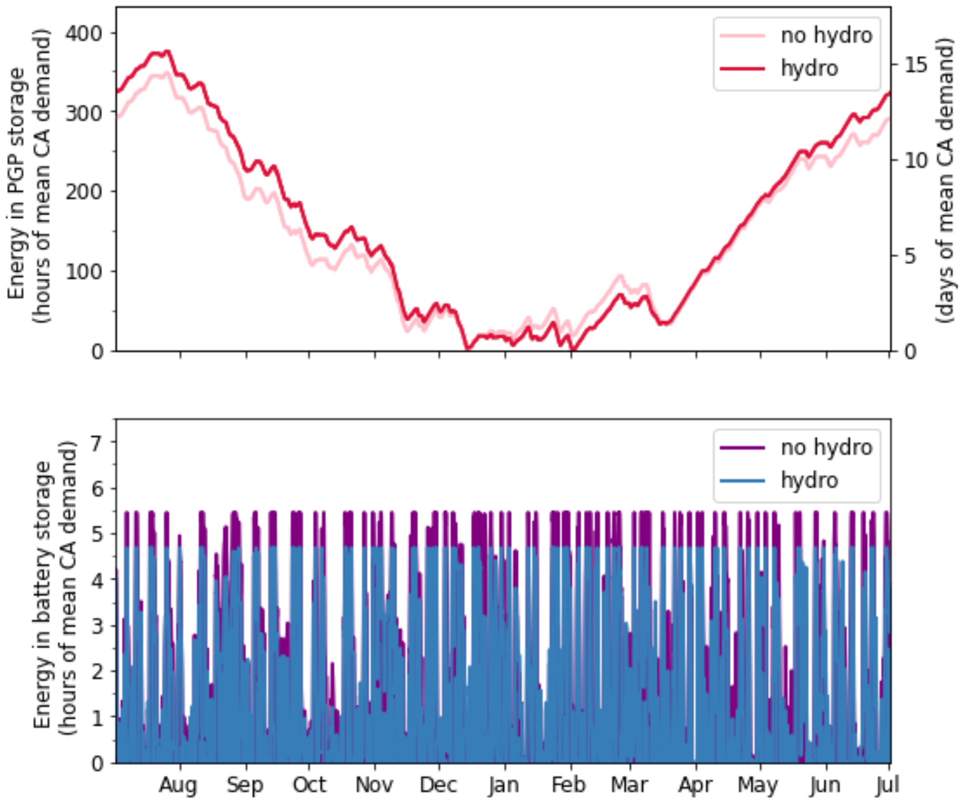

Figure S13: Energy storage during one year for systems with and without hydroelectric dispatch. Energy in PGP storage (top) and battery storage (bottom) over one year from July to July. These results are from optimizations using the normalized CA and hydro adjusted CA demand as described in Figure S6. When hydroelectric dispatch is subtracted from California electricity demand, the resulting least-cost system includes slightly more installed PGP energy capacity (15 days of mean CA demand vs. 14 days without hydro) and slightly less installed battery energy capacity (4.7 hours of mean CA demand vs. 5.5 hours without). The costs of these two systems were fairly similar at 0.14 $/kWh without hydroelectric generation and 0.13 $/kWh with hydroelectric generation.

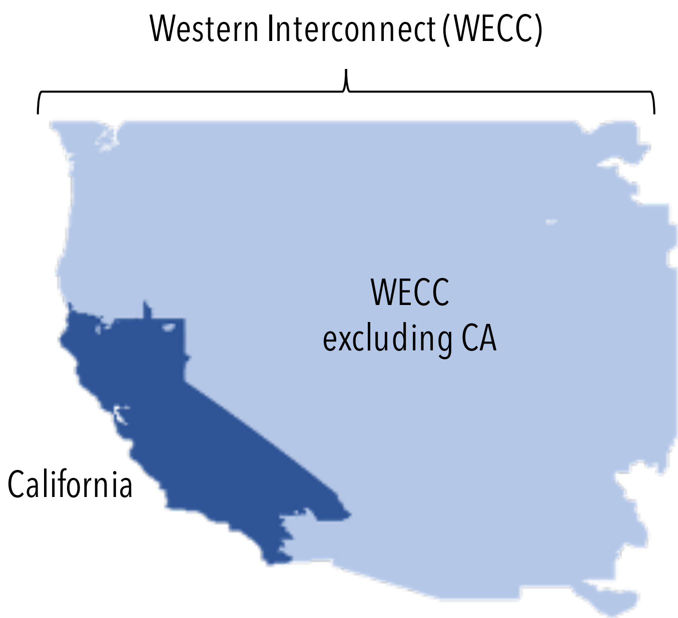

Figure S14: Regions used to generate resource datasets. The plotted shapefiles specify the regions were used to generate the wind and solar resource datasets used in this study. The shapefiles are originally from the Environmental Protection Agency's eGRID Mapping Files.[2] We chose the CAMX region which includes all major cities in California because of its overlap with the balancing authorities (BANC, CISO, LDWP, and TIDC) used in the demand data.

3. Supplementary cost information

3.1 Natural gas with carbon capture, sequestration, and storage (CCS)costs

Costs for Natural Gas with CCS	
Technology description	Advanced combined cycle with carbon capture and storage
Total overnight capital cost ($/W)[3]	2175
Fuel cost ($/MMBtu)[4]	3.56[a]
nth-of-a-kind heat rate (Btu/kWh)[3]	7493
Fixed O&M cost ($/kW/yr)[3]	33.75
Variable O&M cost ($/MWh)[3]	7.20
Project life (yrs)[5]	20
Heat content of electricity (Btu/kWh)[6]	3412.14
Calculated levelized costs	
Fixed cost ($/kWh)	0.027
Variable cost ($/kWh)	0.066

Table S13: Cost and technological assumptions for natural gas with CCS. This table supports Figure S9 and Figure S10. For an example calculation of the fixed and variable costs reported in this table, see Section 7.2.
[a]This cost is for natural gas with CCS delivered for electricity generation for the United States. The cost of natural gas with CCS delivered electricity generation for California is slightly higher at 4.5 $/MMBtu, but the US cost was used to maintain consistency in costs isolate the effects of resource availability when comparing different regional examples.

7.2 Example calculation of the fixed and variable costs for natural gas with CCS

These calculations support Table S2.

Efficiency

$$\text{Efficiency} = \frac{\text{heat content of electricity}}{\text{heat rate}} = \frac{3412.14\ \frac{\text{Btu}}{\text{kWh}}}{7493\ \frac{\text{Btu}}{\text{kWh}}\ [39]} = 0.4554$$

Fuel Cost

$$\text{Fuel cost} = \text{fuel cost (thermal)} + \text{fuel cost (electric)}$$

To put everything in terms of $/kWh-electric:

$$\text{Fuel cost} = \frac{\left(\frac{\text{Fuel cost (thermal)}}{\text{heat content of electricity}}\right)}{\text{efficiency}} + \text{fuel cost (electric)}$$

$$\text{Fuel cost} = \frac{\left(\frac{\$3.56}{\text{MMBtu}}\right)\left(\frac{1\ \text{MMBtu}}{0.293\ \text{MWh}}\right)\left(\frac{1\ \text{MWh}}{1000\ \text{kWh}}\right)}{0.4554} + 0\,\frac{\text{mills}}{\text{kWh}} = 0.0267\ \$/\text{kWh}$$

Variable Cost

$$\text{Variable cost} = \frac{\text{Fuel cost}}{\text{Efficiency}} + \text{Variable O\&M costs}$$

$$\text{Variable cost} = \frac{0.0225\ \frac{\$}{\text{kWh}}}{0.4554} + \frac{7.2\ \frac{\$}{\text{MWh}}}{\left(\frac{1000\ \text{kWh}}{\text{MWh}}\right)} = \mathbf{0.0658}\ \mathbf{\$/kWh}$$

Capital Recovery Factor

$$\text{Capital recovery factor} = \frac{\text{Discount rate} \times (1 + \text{Discount rate})^{\text{Assumed lifetime}}}{(1 + \text{Discount rate})^{\text{Assumed lifetime}} - 1}$$

$$\text{Capital recovery factor} = \frac{0.07 \times (1 + 0.07)^{20}}{(1 + 0.07)^{20} - 1} = 0.09439 \approx 9.44\%$$

Fixed Cost

$$\text{Fixed cost} = (\text{Capital cost} \times \text{Capital recovery factor}) + \text{Fixed O\&M cost}$$

$$\text{Fixed cost} = \left(\left(\frac{\$2175}{\text{kW}} \times \frac{9.44\%}{\text{year}}\right) + 33.75\frac{\$}{\text{kW} \cdot \text{year}}\right) \times \frac{1\ \text{year}}{8760\ \text{hours}} = \mathbf{0.02727}\ \mathbf{\$/kWh}$$

Citations

(1) United States Energy Information. Net generation from hydro for California Independent System Operator (CISO), hourly - UTC Time. https://www.eia.gov/opendata/qb.php?category=3390127&sdid=EBA.CISO-ALL.NG.WAT.H (accessed Sep 22, 2020).

(2) US EPA, O. eGRID Mapping Files: eGRID2016 Subregions https://www.epa.gov/egrid/egrid-mapping-files (accessed Sep 29, 2020).

(3) United States Energy Information (2018). Assumptions to the Annual Energy Outlook 2018: Electricity Market Module. **2018**, 31.

(4) United States Energy Information. EIA Electric Power Annual 2018, Technical report. Table 7.20: Average Cost of Natural Gas Delivered for Electricity Generation by State, 2018 and 2017. https://www.eia.gov/electricity/annual/html/epa_07_20.html?fbclid=IwAR3tnM--aoSr52WrnWQKOQ29rL7G7zoXzZkZH6NfFoLeRudV9vFLvwB9emo (accessed Sep 16, 2020).

(5) United States Energy Information. Assumptions to the Annual Energy Outlook 2018: Commercial Demand Module. Table 2. 2018.

(6) United States Energy Information. Monthly Energy Review – August 2020. Table A6. **2020**, 272.